

Investigation of hydrocarbon and non-hydrocarbon (CO₂, N₂) gas injection on enhanced oil recovery in one of the Iranian oil fields

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Abstract Masjed-I-Suleyman (MIS) field is the first field in the Middle East that has produced oil and has such a long production history (100 years). This field's production started in 1911. Most of the oil production in the Middle East come from carbonate reservoirs, the majority of which are fractures. These reservoirs tend to produce at high rates in their early production period followed by low rates later on, leading to low overall recovery. The early production rate of this field was 120,000 stb/day, now reaching about 2,000 stb/day. MIS field has produced 1.39 billion stb of oil as of 1 January 2010, which makes it a giant field by world standards. 267 million of this produced oil was re-injected into the reservoir and if the recycled oil re-injected into the reservoir is included, the net total oil produced as of 1 January 2010 would be 1.123 billion stb. Based on original oil-in-place of 6 billion stb, the recovery factor equates to 23.2 % (based on the gross oil production) or 18.7 % (based on the net oil production). So this reservoir is a candidate for an EOR process. It seems the gas injection into oil reservoirs is one of the most effective methods in EOR approaches (Ganji and Haghighi 2006). In this study, the injection technique that was used includes gas injection with different fluids that causes an immiscible process. A compositional reservoir simulator has been used to determine the effect of the gas injection process on reservoir production to optimize the oil recovery for the MIS field. Simulation results show that gas injection is not useful for this field.

Keywords Gas Injection · Compositional Simulator · EOR

Introduction

The Masjed-I-Suleyman (MIS) field is a large onshore production field located in Southwest of Iran (Fig. 1) and began production in 1911. The reservoir rock of the MIS reservoir is a marine fissured limestone named after the Asmari Mountain. The reservoir thickness is of about 1,000 ft and it is about 2,450 ft from the crest of the structure to the initial water–oil contact. The goal of this study is an investigation of several production strategies to optimize the recovery of MIS field. A summary of the history of this field is as follows:

- Although over 220 wells have been drilled, only 121 wells have ever produced. Production started in 1911. However, not more than 31 wells were in production at any time.
- The reservoir can be represented by six geological zones (with zone 1 on the top). Zone 4 is very anhydritic. Zone 6 is very tight and can be ignored in the volumetric oil-in-place calculation (Speers 1975).
- Of all the wells drilled, only 22 wells were logged. Of the 22 logs, only 5 logs reach zone 6 and only 2 are modern logs. This results in uncertainties in some of the key reservoir parameters (e.g., net pay, porosity, initial water saturation) especially for the lower zones.
- Since all the 22 logs were taken from the more fractured (and likely better) part of the reservoir, the reservoir qualities and original oil-in-place determined from log data are expected to be optimistic.
- There were only two routine core analyses and only one of them covers all zones. Only one well has both core and log to allow cross-calibration.
- Based on the cumulative oil production and oil-in-place, the entire field may be subdivided into six

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Fig. 1 The location of the MIS field

drainage areas for study and reporting purposes. Correction factors were used to describe the different reservoir qualities in different drainage areas, and to account for additional risk in areas with less well control.

- There was no PVT analysis at virgin reservoir conditions. There was only one PVT test conducted in 1964. Unfortunately, at the time of the test, over 1.2 billion stb of oil had already been produced and the reservoir datum pressure had dropped to 450–550 psia, which is below the original bubble point pressure (619 psia).
- Although the field started production in 1911, there is no record of individual well production rates (yearly, monthly or daily) before 1939. Only cumulative oil production for each well has been recorded.
- Since 1939, 47 wells have had production. The field was completely shut down during the Iran-Iraq war, from 1981 to 1988. Since 1988, only 12 South Flank wells have had production and all the North Flank wells have been shut-in.
- There was an internal gas blowout from April 1964 to the end of 1967. Over 400 BCF of Jurassic gas has entered the Asmari formation. During this period, some dome gas was flared to release pressure. In 1968, there was another smaller uncontrolled gas blowout from the Asmari gas cap. This blowout lasted for 88 days and an estimated 32 BCF of Asmari gas was released.
- From 1929 to 1975, the surplus product from the refinery and from the MIS topping plant was re-injected back into the Asmari formation. The total amount of recycled injection was 267 MMSTB, which amounts to about 20 % of the total oil produced as of the end of 1975.
- Two volumetric (static) oil-in-place calculations were performed. The first one, based on the Monte Carlo simulation, yields a mean STOIP of 7.6 billion stb. Another probabilistic calculation yields a mean STOIP of 6.3 billion stb. If a small reduction is made in the oil-in-place to account for the poorer reservoir qualities in certain parts of the reservoir (e.g., the North Limb and South Limb), it is quite possible to reduce the Monte Carlo STOIP to make it much closer to 6.3 billion stb.
- Two material balance calculations were also performed. The one by (Paravar 2000) yields original oil-in-place of 7 billion stb and the other one by (ECL 2002) yields original oil-in-place of 6 billion stb.

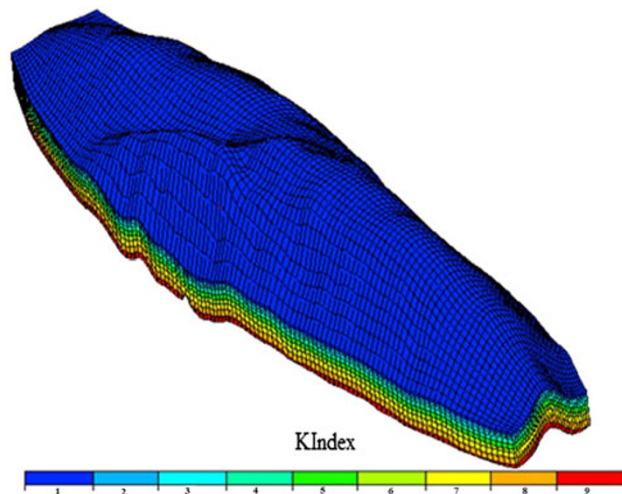


Fig. 2 Three-Dimensional view of the MIS Asmari reservoir

Table 1 Porosity: dual porosity model

Asmari stage	Zones	Matrix porosity (%)	Fracture porosity (%)
6	1	0.11	0.0022
5	2	0.11	0.0022
4	3	0.12	0.0024
3	4	0.14	0.0028
2	5	0.12	0.0024
1	6	N/A	N/A

Table 2 Horizontal and vertical permeabilities: dual porosity model

Drainage area	Correction factor	k_x (mD)	k_y (mD)	k_z (mD)
Core “A” (Forelimb “A”)	1	4,766	4,766	4,766
Core “B” (Forelimb “B”)	1.23	5,862	5,862	5,862
Backlimb “A”	0.45	2,145	2,145	2,145
Backlimb “B”	0.45	2,145	2,145	2,145
North limb	0.2	0.953	953	953
South limb	0.32	1,525	1,525	1,525

It is believed that the true material balance original oil-in-place should be between 6 and 7 billion stb.

From a reservoir engineering point of view, many key parameters are not known because the field was discovered such a long time ago and the technology at that time was very different from the technology today. The parameters that are either not known or are not certain are

- Initial reservoir pressure
- Bubble point pressure
- Initial solution gas–oil ratio
- Initial oil and water saturation

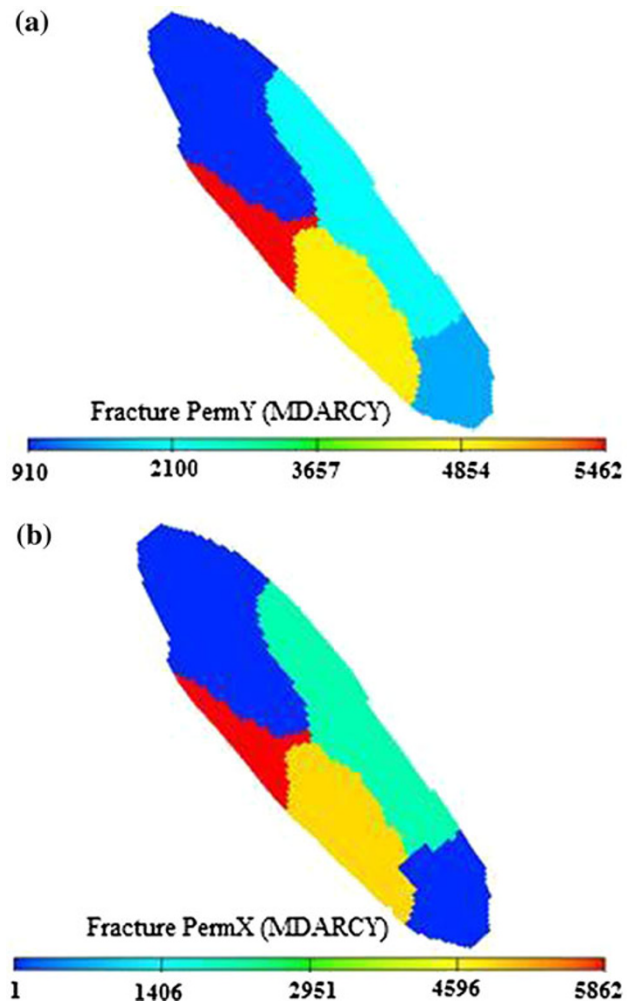


Fig. 3 Map of simulator fracture permeability **a** k_y and k_z , **b** k_x

Table 3 Net-to-gross: dual porosity model

Asmari stage	Zones	Matrix net-to-gross ratio	Fracture net-to-gross ratio
6	1	0.64	1
5	2	0.54	1
4	3	0.5	1
3	4	0.52	1
2	5	0.62	1
1	6	N/A	N/A

Data gathering and preparation

The first step in reservoir simulation is data gathering and preparation. This section of the paper presents the reservoir properties used in the dual porosity model. Reservoir properties such as porosity, permeabilities (horizontal and vertical) and net-to-gross ratios for both the matrix and fractures were based on the geotechnical study and the

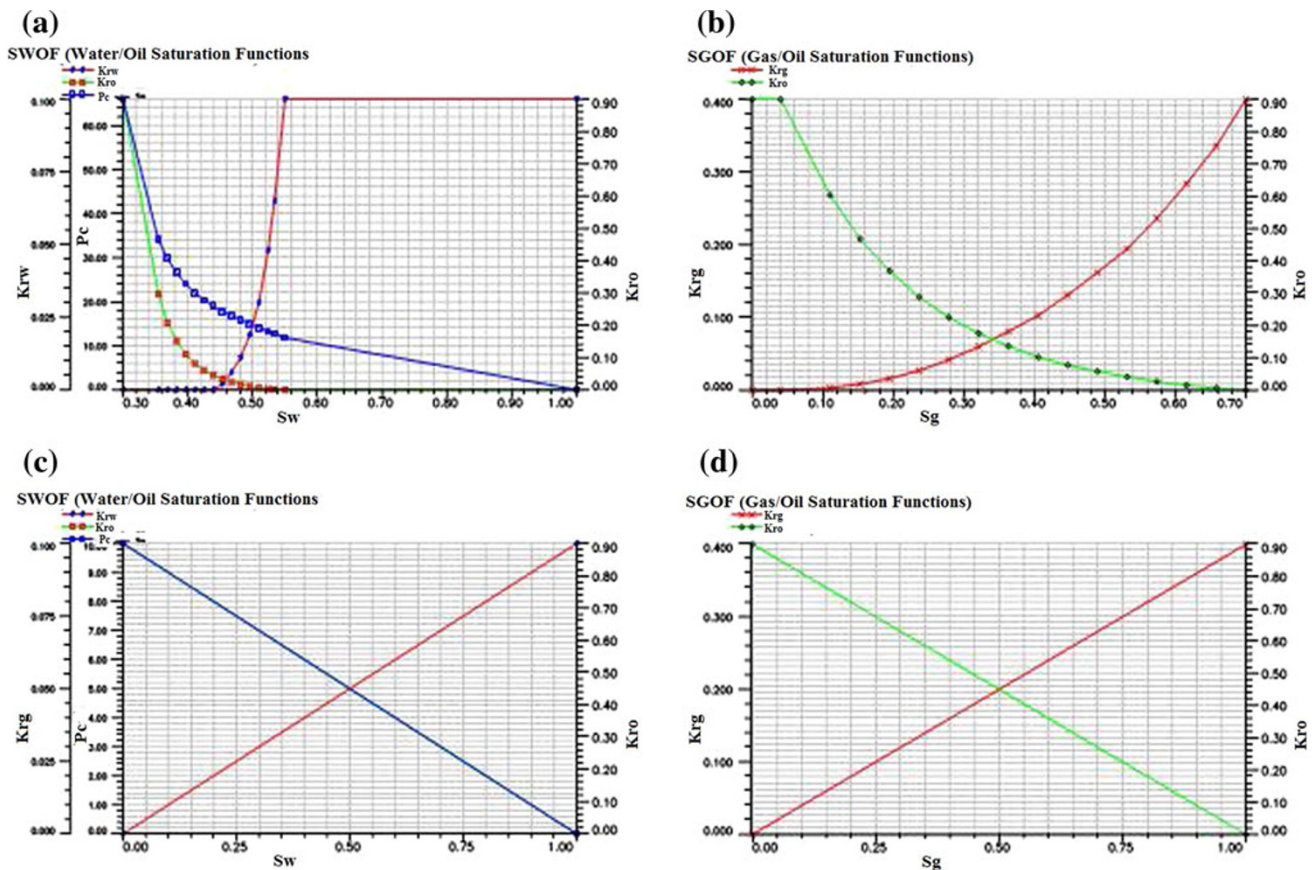


Fig. 4 **a** Oil–water capillary pressure and relative permeability data: matrix, **b** gas–oil relative permeability data: matrix, **c** oil–water capillary pressure and relative permeability data: fracture and **d** gas relative permeability data: fracture

construction and initialization of a dual porosity model for the MIS Asmari reservoir was presented. In the following sections, various data used for reservoir simulation is presented.

Model construction

As mentioned earlier in “Introduction”, the MIS Asmari reservoir has six zones. The model was constructed on the basis of the structure maps (six structure maps for the top of each Asmari zone and one structure map for the base Asmari) obtained in the geotechnical study. In order to have more accurate results, zone 1 was subdivided into three layers and zone 2 was subdivided into two layers. Therefore, the dual porosity model has 18 layers (9 for the matrix and 9 for the fractures). It has a grid dimension of $30 \times 125 \times 18$. A three-dimensional view of the MIS Asmari reservoir is shown in Fig. 2.

Porosity in matrix and fractures

There were only 22 well logs and 2 routine core analyses available for MIS. The matrix porosity was found to be

very close to a constant for each zone (i.e., very uniform). Therefore, a constant porosity was used for each zone in the matrix. The fracture porosity was assumed to be 2 % of the matrix porosity (see Table 1). Pore volume multipliers were later used to adjust the pore volume and the oil-in-place. This adjustment was found necessary in order to match the regional pressures for the North and South flanks. Pressure decline is very much related to the oil-in-place.

Permeabilities in matrix and fractures

Permeability in the matrix is very low for the Asmari carbonate reservoir in the MIS field. Since a dual porosity model is used, fluids can only flow from fracture cells to neighboring fracture cells and production occurs only from the fractures. Therefore, for simplicity, a constant permeability of 3 mD was used for all layers and all directions (i.e., k_x , k_y and k_z) in the matrix.

The horizontal permeabilities (k_x and k_y) are based on reservoir quality correction factors. The correction factors can be considered as risk factors to reflect the lower reservoir qualities in certain parts of the field.

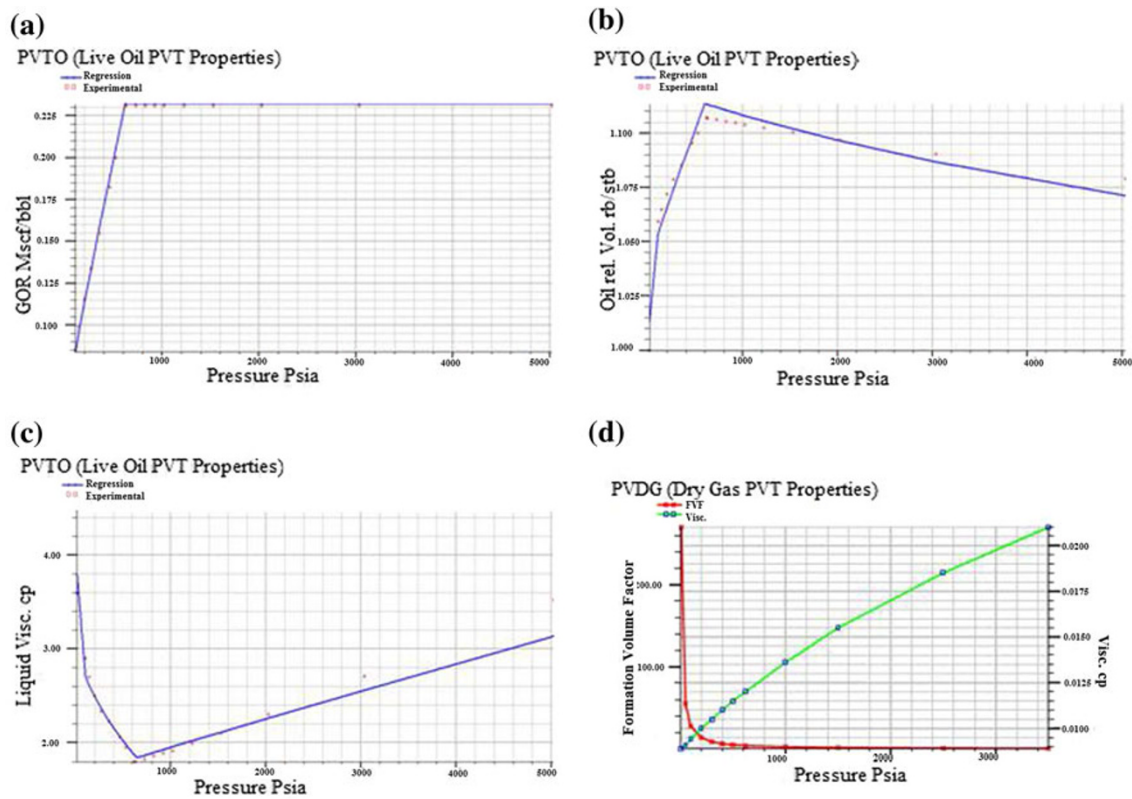


Fig. 5 **a** Gas–oil ratio, **b** oil relative volume factor (B_o), **c** oil viscosity and **d** gas PVT data

Table 4 Reservoir oil and associated gas composition

Composition	Oil (%)	Associated gas (%)
H ₂ S	3.99	0.00
N ₂	0.24	0.77
CO ₂	1.76	5.87
C1	16.81	60.86
C2	6.15	16.21
C3	6.93	9.51
IC4	2.30	1.60
NC4	5.13	2.93
IC5	1.71	0.71
NC5	1.42	0.66
C6	6.37	0.52
C7	6.21	0.26
C8	5.64	0.11
C9	5.79	0.02
C10	4.11	0.00
C11	3.76	0.00
C12+	21.69	0.00

The correction factors have the most impact on the STOIMP calculation. In the STOIMP calculation, the correction factors reduce the oil-in-place to approximately

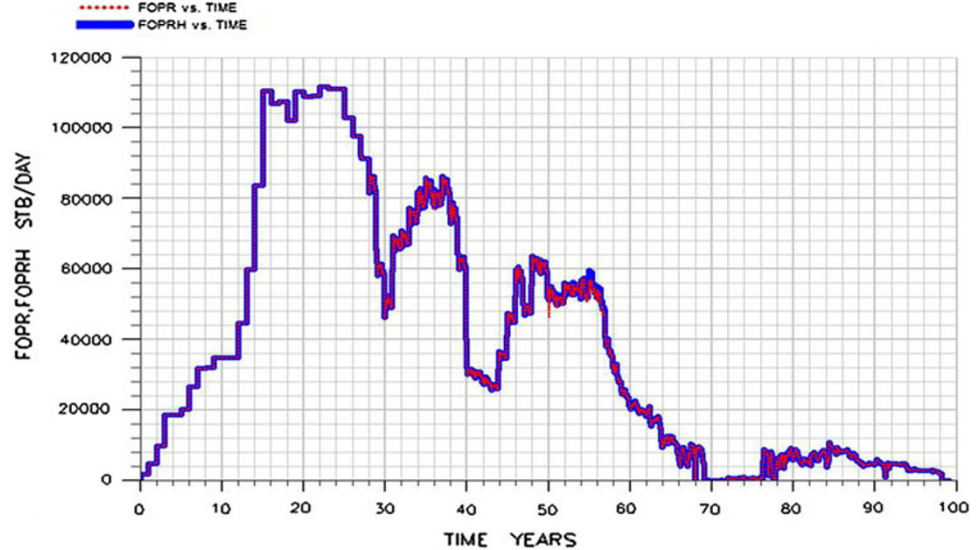
one half. We feel that without the correction factors, the STOIPs (9.3–12.0 billion stb) are on the optimistic side. With the correction factors, the STOIPs are on the pessimistic side.

In that study, the entire reservoir was subdivided into six drainage areas, based on the oil recovery in terms of stb/Ac-ft. A correction factor was assigned to each area to show the relative oil recovery. A correction factor of 1 (one) was assigned to core area “A”, which was considered as the base.

The x -direction permeability, k_x , was assumed to be the same as k_y in the middle part of the reservoir, but reduced 1,000 times in the North and South limbs (ends) of the North flank (Table 2). In addition, the horizontal and vertical permeabilities in the fractures were assumed to be the same for all model layers. Fracture permeability maps k_x , k_y and k_z for all the layers are shown in Fig. 3.

NTG ratio in matrix and fractures

The net-to-gross (NTG) values were also found to be very close to a constant for each zone. Therefore, a constant net-to-gross value was used for each zone in the reservoir model in the matrix. In the fracture system, the NTG ratios are all 1 (open fractures) (Table 3).

Fig. 6 Field oil production rate**Fig. 7** Cumulative oil production

Relative permeability data (using SCAL)

The oil–water and gas–oil relative permeability data are plotted in Fig. 4: a and b are for the matrix; c and d are for the fractures.

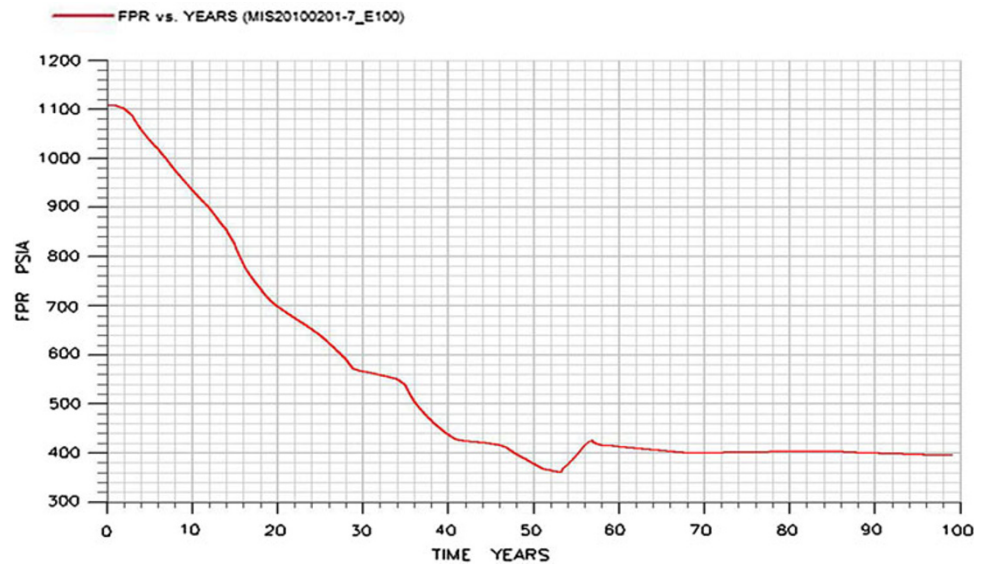
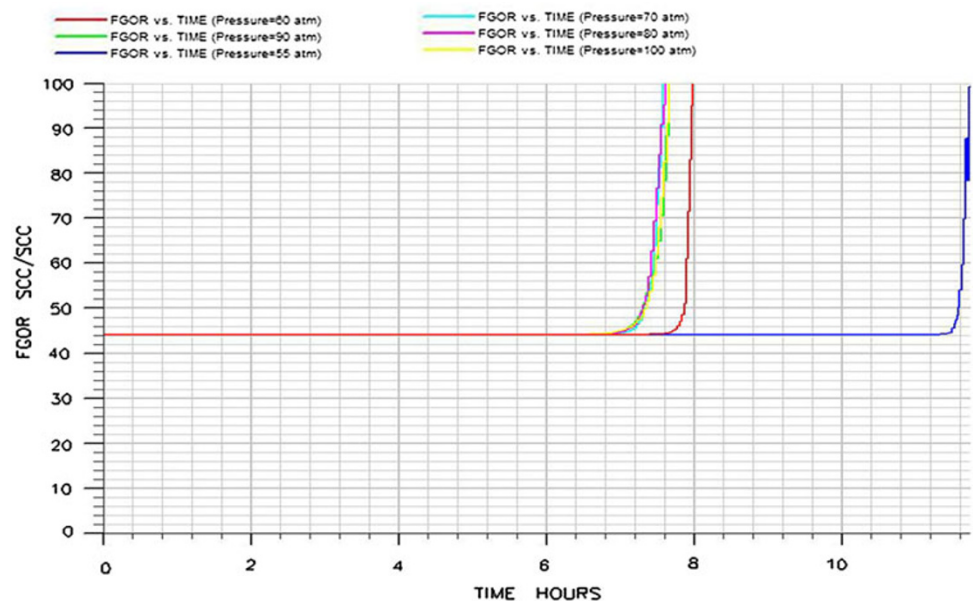
PVT data

Bottom-hole fluid samples were obtained on four wells over the period from September 1964 to April 1966. Only one full fledged PVT analysis was conducted on one of these fluid samples on September 1964. In addition, at the time the sample was taken, 1.2 billion stb of oil had already been produced and the average datum pressure had dropped from 450 to 550 psia (much below the expected bubble point pressure of 619 psia). In other words, there

was no fluid sample taken under virgin (initial) reservoir conditions. According to four reports published by various people or companies, the following bubble point pressures are given:

- 625–850 psia: Gibson report [1948](#)
- 621 psia: BP research centre [1962](#)
- 619 psia: Epic report [1999](#)
- 619 psia: NIOC (or psig)

The bubble point pressures from the last three sources are practically the same. Therefore, the decision was made to use 619 psia, which is the number used by the NIOC. As said before, when the PVT sample was taken, the pressure was already below the original bubble point pressure and some solution gas had already been released. Therefore, both the oil formation volume factor and the solution

Fig. 8 Average field pressure**Fig. 9** GOR at various pressures

gas–oil ratio need to be extrapolated to a higher bubble point pressure of 619 psia. So after making a number of assumptions in this area, the PVT data for oil and gas are plotted in Fig. 5 and the composition of oil and associated gas are given in Table 4.

Aquifer specifications

In the MIS reservoir model, the aquifer is very weak. The Fetkovitch analytical aquifer model was used. The aquifer size and strength were specified. Aquifer influx and pressure were calculated for each time step by the simulator. For MIS, two unsteady state aquifers in the model were used, one

aquifer attached to the South flank and the other one to the North flank. In the history match, aquifer strength (aquifer productivity index, PI) and aquifer volume were adjusted until the regional datum pressures for the South flank and the North flank were matched. The aquifer attached to the South flank is much weaker than that to the North flank.

Initialization

The model initialization properties are as follows:

- Initial pressure: 1,200 psia at the datum depth (1,727 ft or 526.4 m subsea)

Fig. 10 Cumulative oil production at various pressures

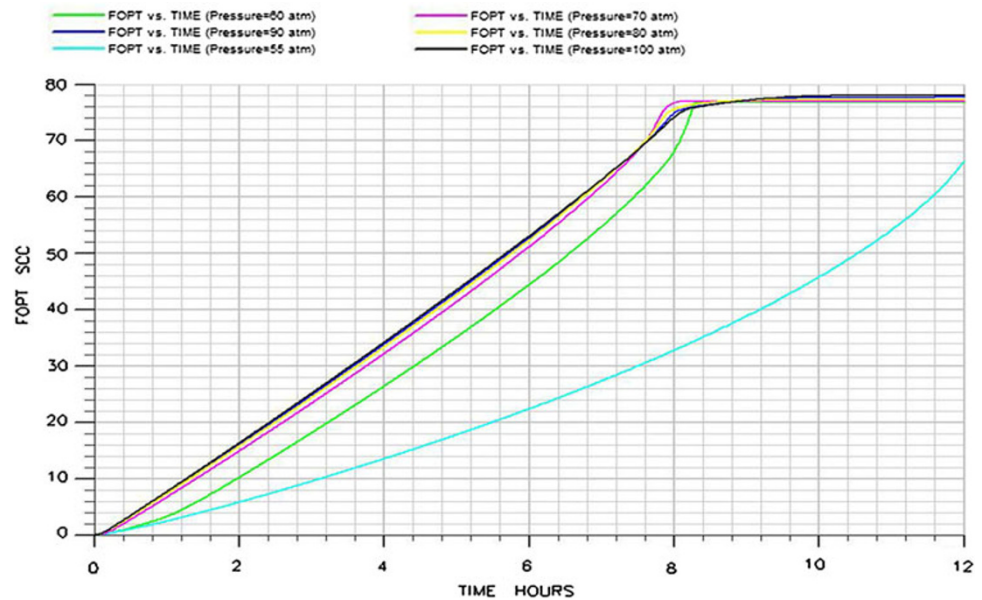


Table 5 Ultimate recovery at various pressures

P	RF
3000	86.14
4000	92.43
4500	96.39
5000	98.71
5500	99.8
6000	99.96
7000	99.96

Table 6 MMP of injective gases into MIS field

Gas type	MMP (psia)
N ₂	11,103
CO ₂	1,260
Associated gas	4,575

- Initial gas–oil contact (GOC): –220 ft or 67.0 m subsea (i.e., top of the reservoir)
- Initial water–oil contact (WOC): 2,160 ft or 658.4 m subsea.

In addition, a uniform solution gas–oil ratio (GOR) of 231 scf/stb was specified for the entire system.

Full field history match

In the full field history match for the MIS Asmari reservoir, the primary data to be matched are total field oil production rate, total field cumulative oil production, and regional datum pressures for the North and South flanks.

Unlike most simulation studies, water cut and GOR were not primary data to be matched for the following reasons.

- For the MIS Asmari reservoir, there were no records or reports of measured water cut. Water production was very low.
- Similarly, there were no accurate and reliable measurements of gas production that can be used in the history match. Prior to 1965, the producing GOR was reported as 231 scf/bbl. Obviously, this represented the initial solution GOR of the reservoir fluid. As long as the flowing bottom-hole pressures of the wells were

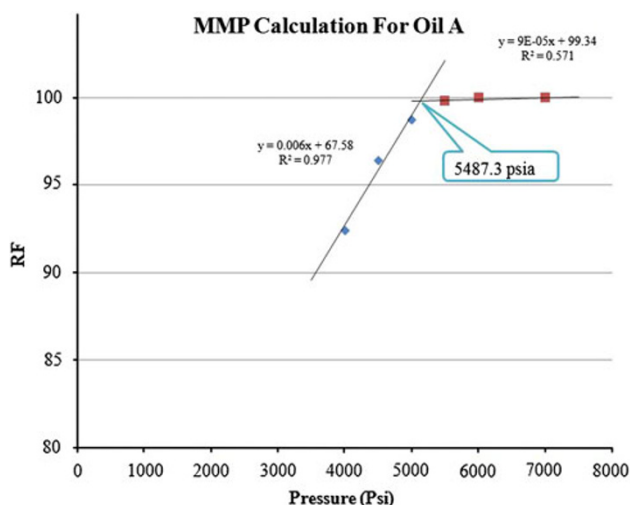
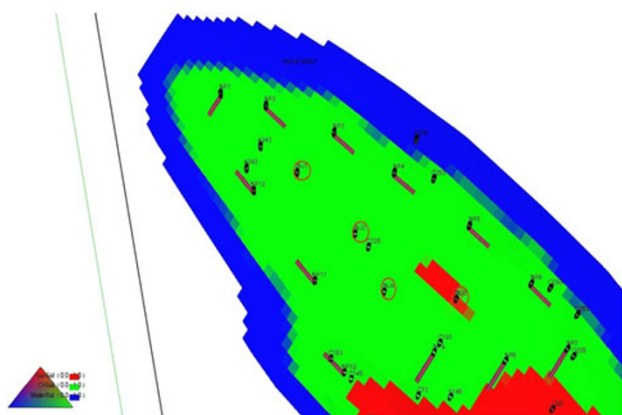
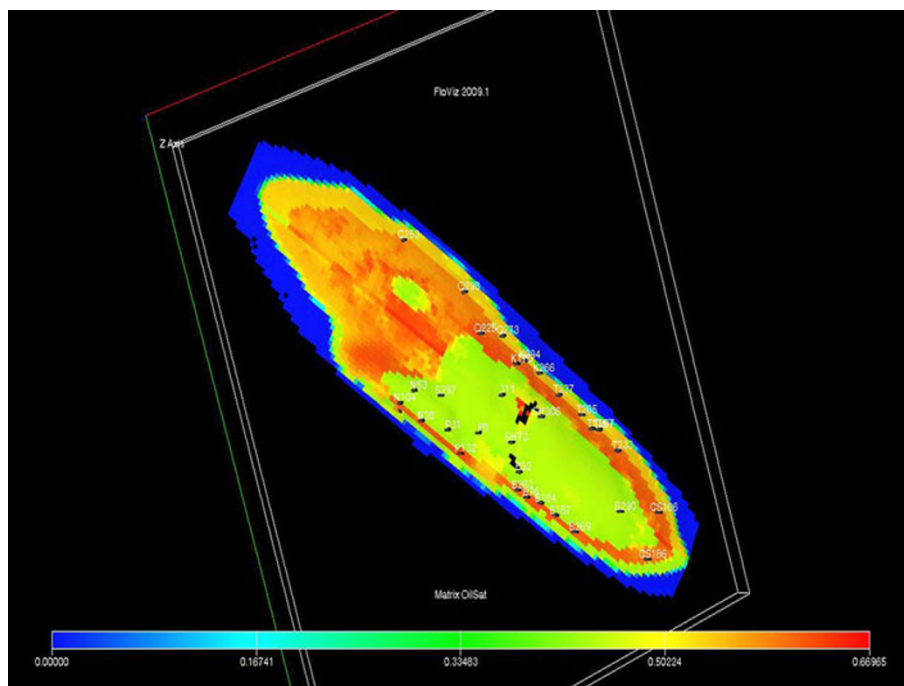


Fig. 11 RF versus pressure to determine MMP

Fig. 12 Map view of the S_o **Fig. 13** Map view of the well's locations

still above the bubble point pressure, the producing GOR should be equal to the initial solution GOR, provided that there was no significant gas coning.

The secondary parameters to be matched are gas pressure (in the gas cap), GOC in the fractures for the North and South flanks and WOC in the fractures for the North and South flanks.

The model results are provided in Figs. 6, 7, and 8.

Determination of MMP by compositional slim tube simulator

A compositional simulator was used to determine the MMP for various gases. The ECLIPSE® E300™ was used. This model has 100 grids with porosity of 0.2 and permeability of

1,000 mD. In this model, the length was selected as 20 m and 0.5 cm for the width and height to minimize the effect of transition zone length. Smaller diameter tubing is justified to prevent viscous fingering (Elsharkway et al. 1992). The relative permeability graph does not have any effect on results (Lars and Whitson 2000). (residual oil saturation is equal to zero) oil recovery at 1.2 pore volumes of injected gas is plotted as a function of pressure. The break-over pressure in these recovery curves is deemed the MMP.

First, the model should be validated. For this purpose, oil A (Jessen et al. 1998) is used. The GOR and cumulative oil production are shown in Figs. 9, 10. The ultimate recovery factor in each pressure was recorded in Table 5. Oil recovery at 1.2 pore volumes of injected gas are plotted as a function of pressure in Fig. 11. The break-over pressure in this curve occurs at MMP equal to 5487.3 psia. The MMP from slim tube for this oil was 5445 psia. So the relative error is 0.77 %. Hence, this model has a good accuracy to predict MMP. After several runs, the MMP for injective gases in this paper for the MIS field are calculated and results are shown in Table 6.

It can be observed that all of these MMPs are above the MIS reservoir pressure. So gas injection in this field is an immiscible process.

Reservoir simulation scenarios and discussion

In this study, the section of the reservoir for investigation was selected so that S_o is more than other places (Fig. 12). The pressure in this section of the reservoir is in the range

Fig. 14 The rate of injection and production

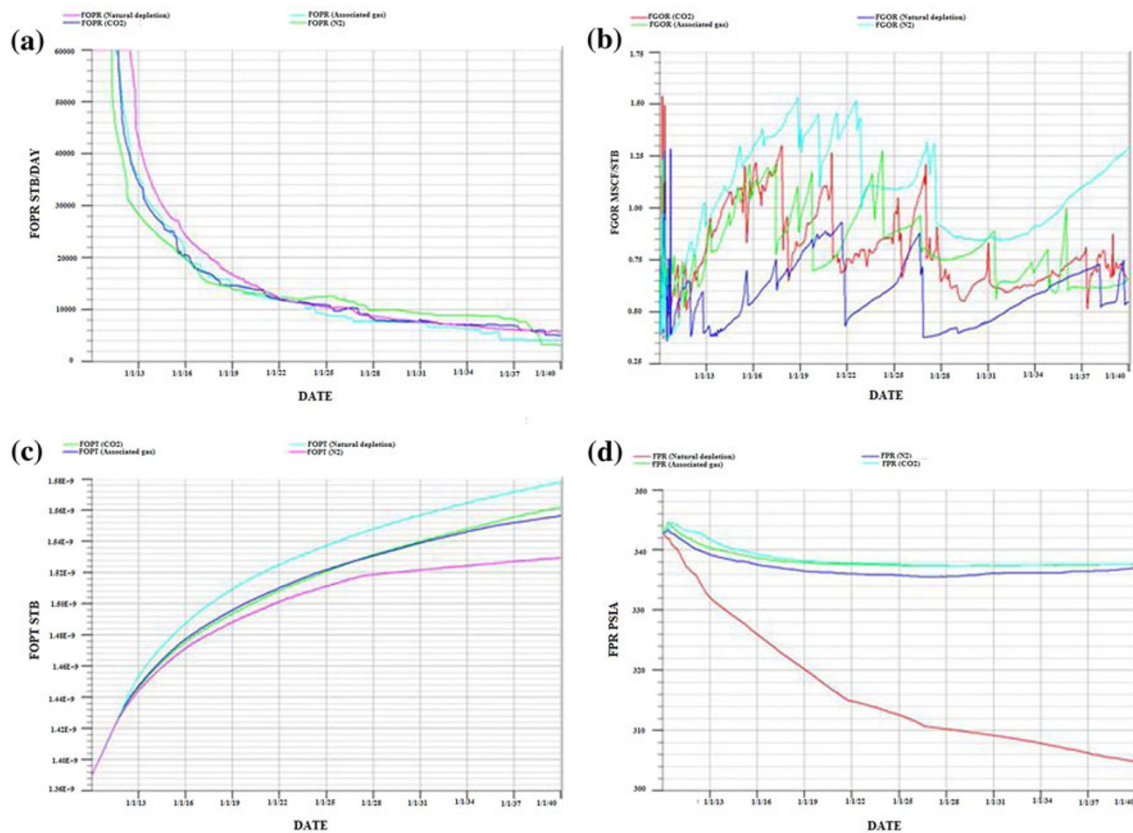
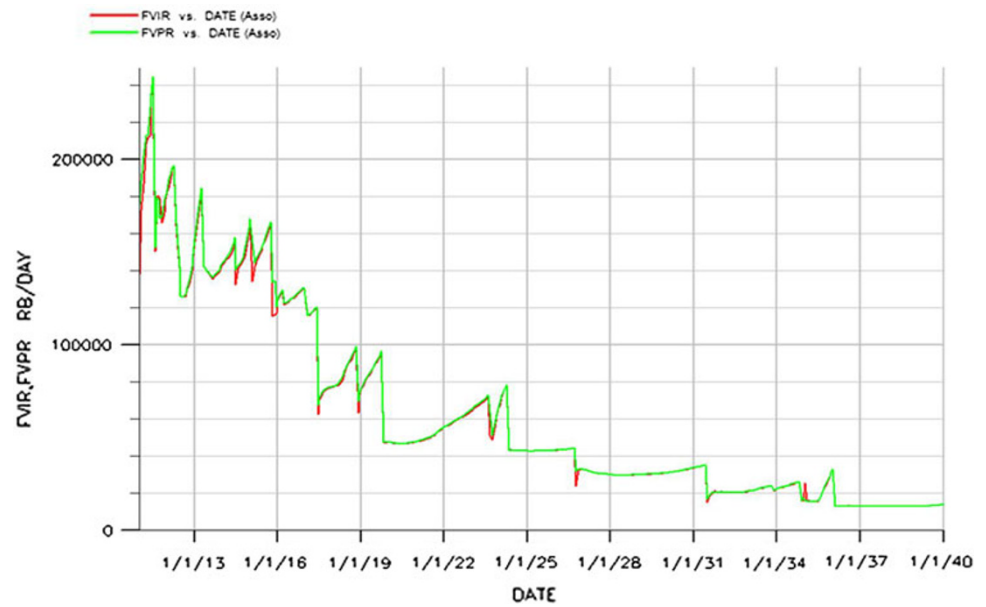


Fig. 15 **a** Oil production rate for various gases and natural depletion, **b** GOR for various gases and natural depletion, **c** cumulative oil production for various gases and natural depletion and **d** pressure changes during injection and natural depletion

of 350–450 psia. Prediction runs were made using the preliminary history match model described in “[Data gathering and preparation](#)”. In general terms, locations of

the new wells were based on the number of new wells to be drilled, surface topography, and subsurface reservoir constraints. After taking various runs, twelve horizontal wells

Table 7 RF for various gases

Gas type	RF (%)
Natural	4.27
CO ₂	3.9
N ₂	3.17
Associated gas	3.78

are planned all of which are perforated in the third layer (nearly in the middle of the oil column). Four vertical well injections are located in the center of production wells that are perforated in the third, fourth and fifth layers. A map view of the locations of the 12 new production wells and 4 injection wells are shown in Fig. 13.

The well diameters are 7 inc. The minimum BHP in all cases was set to 250 psia. The economical limits for shutting the wells in all scenarios are given below:

- Maximum GOR: 2,000 scf/stb
- Maximum water-cut: 50 %
- Minimum oil production rate: 200 stb/day

Table 8 RF for various rates

Gas rate	RF (%)
Natural	4.27
0.5 Voidage	4.13
Voidage	3.78
20 MMP	3.75
60 MMP	2.41
100 MMP	2.06

After selecting these parameters, the investigation of different injection fluids that can be used for the optimum method of EOR in this field would be initiated.

Selection of fluid

Different injection fluids including CO₂, N₂ and reservoir gas was injected and the final recovery for each fluid was estimated. Since all of the gases are immiscible, in this step, the injection rate is considered as voidage [volume of fluid

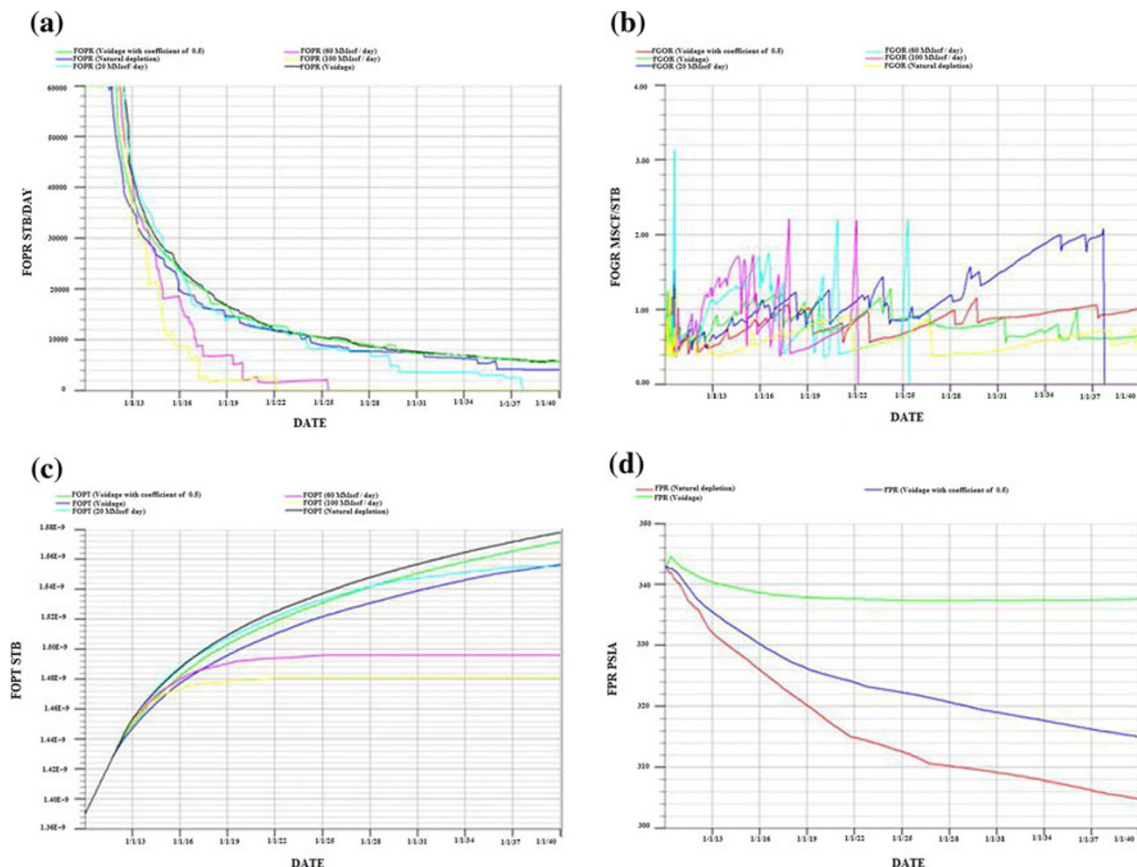


Fig. 16 **a** Oil production rate at various pressures, **b** GOR at various pressures, **c** cumulative oil production at various pressures and **d** pressure changes during injection with various pressures

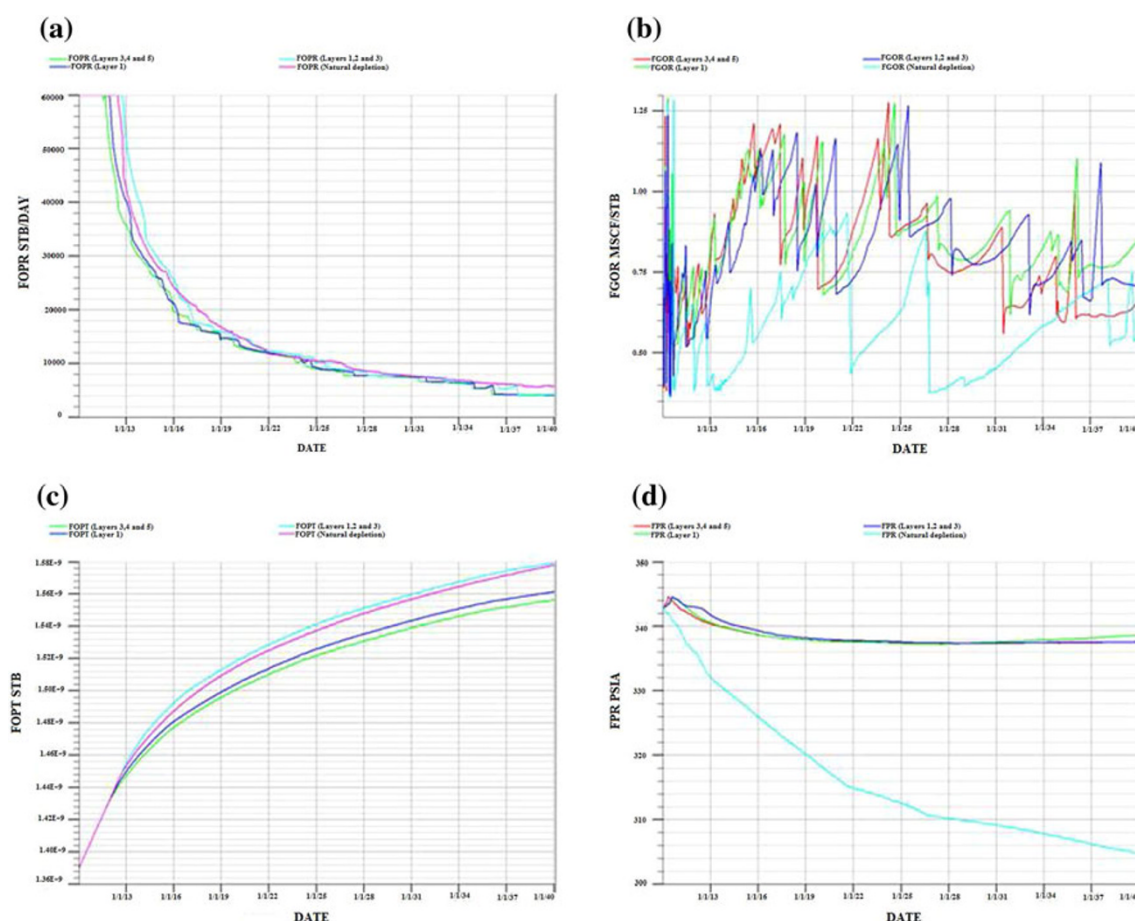


Fig. 17 **a** Oil production rate for various location's perforation, **b** GOR for various location's perforation, **c** cumulative oil production for various location's perforation and **d** pressure changes during injection for various location's perforation

Table 9 RF for various location's perforation

Gas location	RF (%)
Natural	4.27
Layers 3, 4, 5	3.78
Layer 1	3.89
Layers 1, 2, 3	4.3

injected is equal to volume of fluid production (Fig. 14)] and the results are compared with natural depletion.

As evident from the graphs (Fig. 15), the natural depletion has more recovery than others. The reason being, whereas all the gases are immiscible with reservoir fluid, gases move through the fractures toward production wells and then the increase in GOR leads to shutting the wells and thus lowering the oil recovery. The increase in oil recovery throughout these 30 years (from 2010 to 2040) is tabulated in Table 7. It is observed that in each three scenarios, pressure changes are almost negligible (Fig. 15d).

In determining the best gas, the associated gas is in second place (with a slight difference compared to CO₂ that this difference is due to higher power absorption of CO₂ than other gases). But because the supply of associated gas is more economical than CO₂, the optimization of other parameters for this gas needs to be determined.

Optimization of gas injection rate

For this purpose, gas with rates of 20 MMscf/day (each well 5 MMscf/day), 60 MMscf/day (each well 15 MMscf/day), 100 MMscf/day (each well 25 MMscf/day), Voidage and Voidage with coefficient of 0.5 were injected into the reservoir. The results are shown in Fig. 16 and Table 8.

So increasing the injection rate leads to faster movement of gas toward production wells and thus results in sooner shutting and the final recovery will be less (it should be noted that recovery factor in all cases will be less than natural depletion). Whereas in the Voidage scenario

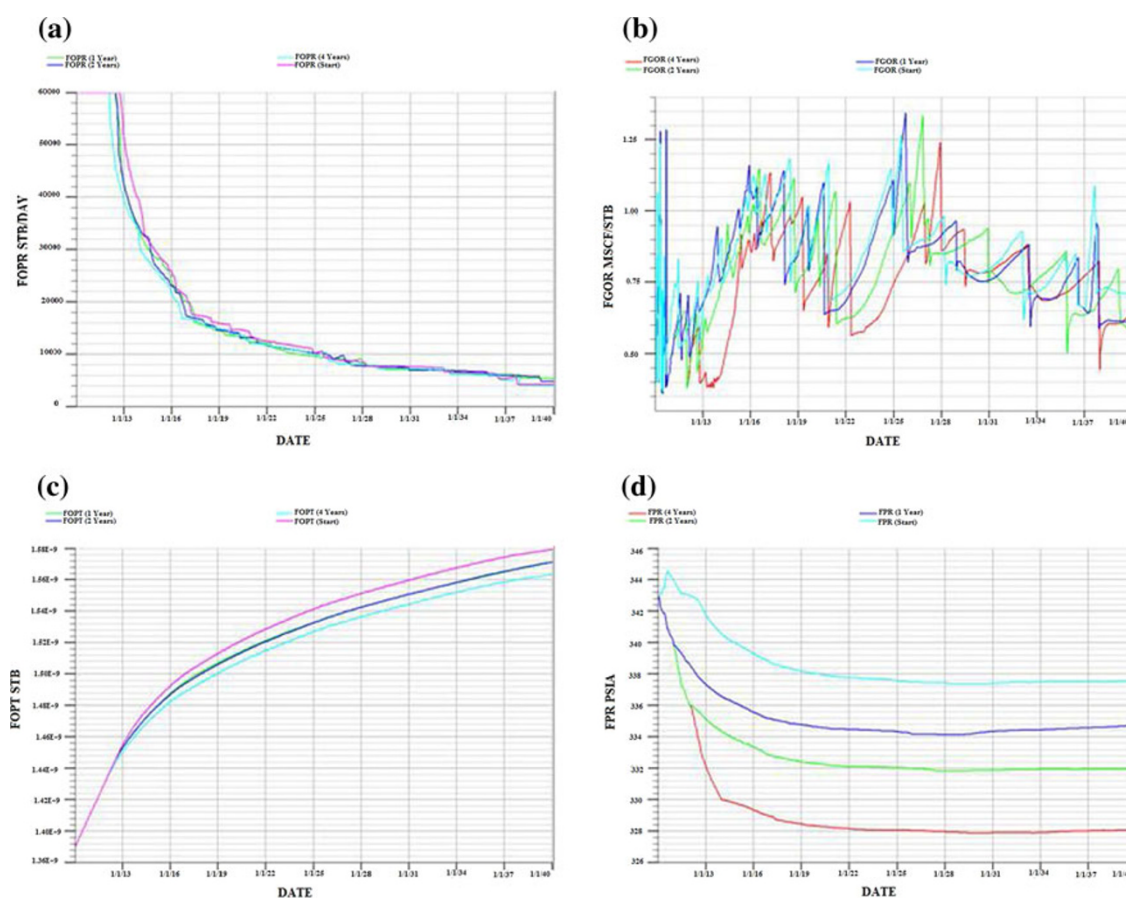


Fig. 18 **a** Oil production rate for various beginning times of injection, **b** GOR for various beginning times of injection, **c** cumulative oil production for various beginning times of injection and **d** pressure changes during injection for various beginning times of injection

Table 10 RF for various beginning time of injection

Gas injection time	RF (%)
Strat	4.3
After 1 year	3.94
After 2 years	4.12
After 4 years	4.11

reservoir pressure remains constant, this scenario is preferred to Voidage scenario with a coefficient factor of 0.5. So the optimization of other parameters will be done on this scenario.

Determining the best location for perforations

In previous cases, the injection wells were completed in layers 3, 4 and 5 (production wells have been completed in layer 3). In this section, injection wells are completed in other layers and the results are compared. In one case, an injection well was perforated in layers 1, 2 and 3 and in another case it was perforated just in layer 1. Figure 17

reflects the results. In the case that gas is injected into the first layer, the process is only a one pressure maintenance process and in the case that gas is injected into layers 3, 4 and 5, most of this gas is injected using the flooding process. And another case is a combination of these two cases which has been the only case having more recovery than natural depletion so far (Table 9). So the optimization of other parameters will be done in this scenario.

Determining the beginning time of injection

Four cases were considered as follows:

- Starting production
- 1 year after starting production
- 2 years after starting production
- 4 years after starting production

And the results are shown in Fig. 18 and Table 10.

As it is obvious from the results, injection at the beginning of production prevents the initial pressure drop (at this time the field production rate is high) and thus greater ultimate recovery will result.

So in the end of all scenarios, the best scenario is as follows:

- Gas type: associated gas
- Injection rate: voidage
- Injection into layers 1, 2 and 3
- Time: at the beginning of production

Conclusion

- MIS field is the first field in the Middle East that produced oil and it started in 1911 (100 years ago). Now, the recovery factor equals 18.7 %. So this reservoir is a candidate for an EOR process.
- The slim tube simulator in this project was validated for two different fluid reservoirs and can be used to calculate the MMP and MME (minimum miscibility enrichment).
- According to the results of the slim tube simulator, all injective gases are immiscible. CO₂ has minimal amounts of MMP. But in the current condition, none of these gases (even CO₂) have the ability to mix with the fluid reservoir.
- Considering that all of the gases were immiscible and the ultimate oil recovery did not experience any significant difference, and because the supply of this gas is more economical than other gases, the optimization of other parameters for this gas needs to be determined.
- Whereas the type of operation is flooding and pressure maintenance, increasing the gas injection rate leads to faster movement of gas toward production wells and thus results in sooner shutting and the final recovery will be less.

- At the end of all scenarios, the best scenario was as follows: associated gas with voidage rate that was injected into layers 1, 2 and 3 at the beginning of production, but the RF difference for this scenario and natural depletion is just 0.03 %. So it can be stated that gas injection is not useful as an increase recovery factor of the MIS field.

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